BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
ROBERT "BOB" BURNS, Chairman
BOYD DUNN
SANDRA D. KENNEDY
JUSTIN OLSON
LEA MARQUEZ PETERSON

IN THE MATTER OF RESOURCE PLANNING AND PROCUREMENT IN 2019, 2020 AND 2021	Docket No. E-00000V-19-0034 SWEEP Report and Analysis on TEP's 2020 Integrated Resource Plan

SWEEP Report & Analysis on Tucson Electric Power's 2020 Integrated Resource Plan

The Southwest Energy Efficiency Project (SWEEP) appreciates the opportunity to provide these comments on Tucson Electric Power's (TEP) 2020 Integrated Resource Plan (IRP). As part of our review of TEP's 2020 IRP and our participation in TEP's IRP Advisory Council, SWEEP commissioned the services of Strategen Consulting[1] to conduct an independent analysis of TEP's IRP. This analysis utilized capacity expansion modeling to identify which portfolios are least cost and should be utilized to meet TEP's electricity demand over the next fifteen years. As one of the members of TEP's Advisory Council, SWEEP and Strategen Consulting had the opportunity to have an open, transparent, and iterative dialogue with TEP on the model's key assumptions, methodology, and results; and the reasoning behind our final recommendations described herein.

Based on the modeling results, SWEEP recommends that the Commission direct TEP to:

- Eliminate coal unit "must-run"[2] designations for future resource planning and modeling,
- Remove modeling restrictions that limit the amount of energy efficiency (EE) that can be selected as a resource option,
- Remove modeling restrictions to allow the economic cycling and economic retirement of coal units,
- Implement the economic cycling and economic retirement of coal (including seasonal operations), and
- Achieve 40% cumulative energy savings by 2030 from a broad portfolio of EE measures.

The modeling results indicate that if TEP implements both economic cycling of coal and 40% energy efficiency by 2030, it could reduce TEP's Net Present Value revenue requirement by $286 million.

We welcome the opportunity to brief Commissioners, Staff, and other stakeholders on our findings and modeling methodology and results.

Ellen Zuckerman
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[1] Strategen Consulting is an internationally recognized boutique consulting practice focused on energy sector market transformation for a low carbon grid. Their functional expertise includes technical and economic analysis including on issues related to integrated resource planning, energy storage, solar, wind, electric vehicles, demand response and energy efficiency. For more information, see: https://www.strategen.com/consulting

[2] "Must-Run" means units remain online and generate electricity regardless of system economics.

Summary of Alternative Resource Plan Analysis for Tucson Electric Power

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Introduction

The following report on the 2020 Integrated Resource Plan (IRP) of Tucson Electric Power (TEP) was prepared by Strategen Consulting on behalf of the Southwest Energy Efficiency Project (SWEEP).

TEP submitted its 2020 IRP to the Arizona Corporation Commission (ACC) on June 26, 2020.[3] As part of its IRP process, TEP engaged in a considerable outreach effort including forming an Advisory Council (AC) to allow for more in-depth discussions with stakeholders. Contributing to this effort, SWEEP partnered with Strategen Consulting to conduct additional grid modeling and technical analysis to identify portfolios that meet TEP's stated objectives in an optimal way, consistent with SWEEP's mission and the following energy policy goals:

- Affordability,
- Reliability of service,
- Risk mitigation, and
- Greenhouse gas (GHG) emission reductions.

Those objectives, although many times presented as competing interests, can not only co-exist without significant trade-offs, but can be simultaneously maximized under the right investment and operational choices. Energy efficiency (EE), renewable energy (RE) resources, and energy storage technologies are becoming more affordable, while they also provide flexibility, and significant environmental benefits without impacting reliability.

This report describes the development of different resource portfolios and the identification of the key portfolio elements that we believe can assist TEP in achieving both a more affordable and cleaner energy portfolio for its customers between now and 2035. In addition to the absence of new fossil resources and the investment in renewable energy and storage, which were common themes in all the portfolios studied by TEP, we also recommend higher investments in energy efficiency, as well as the economic cycling and economic retirement of TEP coal plants. Our recommendations result not only in a reduction of emissions, but also in significant cost savings, while maintaining reliability, mitigating risks, and allowing for a smooth transition to a cleaner portfolio.

Our analytical approach and resulting recommendations were informed by the following research questions:

1. What is the least cost mix of resources for TEP's system?
2. When should coal units be retired based on economic considerations (if given the option)?
3. What are the environmental impacts from early retirement?
4. How should coal units be dispatched if operated based on economic cycling?
5. How much EE is economically optimal when modeled as a resource option versus a fixed load modifying assumption?
6. How does the selection of EE measures impact TEP's energy and capacity needs?

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[3] https://docket.images.azcc.gov/E000007312.pdf

7. How does the selection of EE measures vary based on cost, hourly shape, coincident peak, and savings? And how can this selection be optimized to best meet the evolving needs of the regional power grid (e.g. growing availability of daytime solar)?

Key Findings

Our analysis demonstrated that affordability for customers, as measured by the net present value (NPV) of TEP's revenue requirement, and the subsequent impact on electricity rates, can be achieved in parallel with GHG emission reductions and that in fact there is no trade-off between these two objectives. Specifically, our recommended portfolio is not only the least cost portfolio, but also the one that achieves the highest reduction in emissions.

TEP's preliminary IRP analysis, which was shared throughout the stakeholder process, examined several candidate portfolios, none of which included new fossil fuel generation, and most of which included significant investment in solar, wind, and battery storage technologies. As a starting point, we agreed with TEP that these general trends are sensible and cost effective. As such, we focused our analysis on incremental changes that can result in even further cost and emissions reductions to those that TEP's preliminary analysis showed. Specifically, our findings demonstrated that including the following additional features to TEP's resource portfolio would be beneficial:

- **Achieving 40% cumulative energy savings by 2030 from a broad portfolio of energy efficiency measures.** EE is one of the most cost competitive resources. Higher investment in EE can yield benefits by reducing system peak, saving energy costs, and reducing emissions. The specific portfolio of EE measures can also be tailored to match TEP's evolving load and resource needs.

- **Allowing for economic cycling and economic retirement of coal resources.** Continued operation of coal units is not only environmentally detrimental but results in significant costs for ratepayers due to the high cost and inflexibility of coal relative to other available resources.

Approach

Modeling Methodology

In conducting this analysis, Strategen used the power planning software EnCompass, developed by Anchor Power Solutions[4] in the capacity expansion modeling mode.[5] TEP uses Aurora for its resource planning in the production cost modeling mode.[6]

[4] https://anchor-power.com/encompass-power-planning-software/

[5] Capacity expansion models explore which portfolios are the least cost that should be building to meet electricity demand.

[6] Production cost models explore which portfolios are least cost to dispatch from any generators to reliably meet load in every hour of the day at every location.

Both modeling platforms are commercially available and have been trusted from utilities and decision-makers. They can both be configured either as capacity expansion or production cost models. The different configurations serve to answer different questions as explained below.

A capacity expansion model finds the least cost resource portfolio that meets the projected electricity demand over a period of several years. On the other hand, a production cost model finds the least cost dispatch of a given system of generators. As such, capacity expansion models have been traditionally used to provide investment guidance, while production cost models have been employed to provide answers to shorter-term operational questions or to perform comparisons of pre-selected portfolios. A capacity expansion model uses as input a set of available resources; and selects the ones that can serve the forecasted load over a period of several years at minimum cost. It is, therefore, suitable for an IRP analysis. On the other hand, a production cost model uses as input a pre-specified resource portfolio and focuses only on the optimal dispatch of the various units over a short-term period to meet load. Consequently, this approach can provide a more detailed evaluation of the operational performance of a portfolio but does not necessarily result in the optimal portfolio.

The increasing complexity of energy systems calls for a combined approach in which the capacity expansion model is used to generate portfolios for the next 15 years which are then further studied within a production cost model. Although a combined approach is recommended, the computational intensity of those models and the limited resources and time can many times lead to the selection of only one of the two approaches.

TEP is working to incorporate both modeling approaches in its IRP modeling, but in this cycle it has limited the use of the Aurora model to its production cost capabilities, i.e. TEP has compared the performance of several pre-selected portfolios (the portfolios studies were in turn informed by the AC) and studied their cost, emissions, and technical characteristics by simulating them in Aurora. The objective was to identify the best elements of said portfolios and combine them in TEP's final selection of a preferred plan.

To complement TEP's modeling effort and provide insights into areas of specific interest to SWEEP, such as EE, Strategen conducted capacity expansion modeling using EnCompass. Our approach, while not providing the level of detail in the hourly operational issues that Aurora does, was able to definitively identify the least cost portfolio through an objective cost-optimization modeling approach. This stands in contrast to the approach of hand-picking resource portfolios to be studied in the production cost mode.

Our results have consistently shown that two key elements in achieving lower cost and emissions is the inclusion of cost-effective EE and the economic operations of coal units. These findings were communicated to the TEP IRP team during the Stakeholder engagement process.

Inputs

Horizons Energy provides a dataset accompanying the EnCompass model including all the units, resource characteristics, and grid details of the U.S. power system. Our modeling used the Arizona data from the Horizons Energy database as a starting point. However, during the stakeholder engagement process, we had several calls and interactions with TEP who provided unit specific data (cost and technical characteristics), system planning parameters (import and export limits, planning reserve margin, operating reserves levels), as well as their load forecast, forecast of distributed generation and EE. We incorporated all of the TEP provided data within the original database to ensure that our modeling accurately represents the TEP system.

Coal Units: Operations & Retirement

TEP's supply resources include a significant percentage of coal-fired generation: units 1 and 2 at the Springerville plant account for nearly 800 MW, while TEP's share of units 4 and 5 of the Four Corners Power Plant consists of approximately 110 MW.

Coal Unit Operations

Traditionally, coal units have been considered a baseload resource and were operated to serve baseload demand. They were built to turn on and stay on, running all year round and meet the portion of demand that appears constant in aggregate. Baseload resources have historically had high capital costs but low operating costs, and as such it was economic to run them most of the time, resulting in high capacity factors.

However, coal units are not baseload resources anymore. On the contrary, they now are some of the most expensive resources in an electric system due to the declining cost of alternative technologies including solar, wind, gas, and batteries. Unfortunately, in many regions, despite the clear change in system economics, the past practices of running coal units as baseload resources have not changed, resulting in significant costs for ratepayers. While in real world operations, utilities can choose to operate their units regardless of economic considerations, within a mathematical model that is designed to choose the least cost resources (such as EnCompass), the continued operation of coal units can only be achieved by the introduction of artificial constraints dictating that those units should remain online despite their higher cost. These constraints are often called "must-run" constraints. The relaxation or elimination of such constraints both in the modeling, as well as in real life operations is defined as "economic cycling."

Because must-run constraints have been a common practice in TEP's resource planning, we first ran EnCompass in a similar manner, requiring the continued operation of coal units. This portfolio was then used as the baseline or reference case. Our other portfolios were compared to the reference case to calculate the potential savings that could be achieved by gradually allowing the model to choose increasingly optimal operations instead of enforcing the must-run approach. As expected, the gradual relaxation of those constraints, initially to allow for economic cycling on a seasonal basis, and eventually to allow for full economic cycling throughout the year led to significant savings for ratepayers. These savings are available immediately since coal-fired electricity is already significantly more expensive than that from other currently available resources (even when accounting for construction costs of new resources).[7]

The timing of introducing economic cycling, or at least seasonal cycling, during this IRP cycle is especially important as the coal supply at Springerville is approaching its expiration and the

[7] It should be noted that certain conditions may limit the savings actually achievable by the utility if there are certain limitations (e.g. minimum tonnages) built into its Coal Supply Agreements.

utility will either seek to enter into a new agreement or elect not to enter into a long-term agreement. It is important that the new agreement does not lock TEP into high coal quantities (and high costs) for several years that will eventually lead to unnecessary and otherwise avoidable costs for ratepayers.

Coal Unit Retirement

Our modeling also allowed for economic retirement of the units. Again, historically, both in real world operations, as well as in modeling, units were retired only once they reached their economic book lifetime. However, the dramatic reductions in costs of renewable resources have challenged this practice. Coal units are becoming increasingly more expensive to operate and maintain in a system, introducing the concept of accelerated or economic retirement. The concept has started spreading worldwide as new capital investment in renewable resources, often paired with energy storage, can be much more cost competitive than just the operating expenses of keeping a coal unit in the system. This has led to decisions to retire fossil fuel plants based on economics even before their economic book lives are reached.

Allowing economic retirement means that the model can not only select which units to invest into but can also retire a unit before its scheduled retirement date, if in that way it could achieve cost savings for ratepayers. The decision should be based on a forward-looking analysis, i.e. retirement decisions should account for the avoidable costs, should a unit retire early and not be limited by unavoidable costs associated with a unit's depreciation schedule. Based on economic theory, undepreciated capital expenses should be considered "sunk costs" and should not bear on decisions for which investments should be made.

We recognize that undepreciated costs do exist and that it becomes a policy matter for the Arizona Corporation Commission to decide how and when these "stranded costs" should be recovered if a plant is retired early. However, it is important to recognize that customers are likely to pay these costs regardless of whether the plant is retired or not. Keeping uneconomic units online solely to allow for full book life to be realized only results in higher costs for ratepayers.

Still, we recognize that from the perspective of the utility, accelerated retirement of a unit that has not been fully depreciated, as is the case for the Springerville units, can result in uncertainty and hesitation.

However, we emphasize that regulators have options to treat the remaining value of investments differently and potentially achieve even higher savings for ratepayers, beyond those achieved by replacing the high operational costs of coal with cheaper and cleaner options.

For example, regulators may choose to let the utility continue to charge customers the full rate of return for capital invested in the plant and continue depreciating the plant as if it continued to operate, an option that would result in neither an increase nor a decrease in costs to ratepayers versus the status quo. However, other options available to regulators include the accelerated depreciation of the plant (potentially increasing rates in the near-term but getting the regulatory asset off the books quicker), the exclusion of some investments in the plant from earning a rate of return (if making such investments in an uneconomic plant was determined to be imprudent), or refinancing the unrecovered plant value at a lower interest rate, using a ratepayer-backed bond used to repay the remaining undepreciated plant costs and decommissioning costs. All those options can result in significant ratepayer savings, in addition to the savings from operations and maintenance (O&M) and fuel costs discussed earlier in this study.

Results

To understand the potential savings of coal economic operations and retirement, we ran three models aimed at increasingly relaxing the must run constraints and allowing for economic retirement of coal.

The first run did not allow for economic retirement, but only retired units based on TEP's announced dates. Furthermore, it included must run constraints for all of the coal units. The result of this run served as the baseline portfolio providing a reference NPV of TEP's revenue requirement should the utility continue running its coal units throughout the year.

The second run removed the must run constraints during the September-May period and allowed for accelerated retirement whenever economic. The elimination of the must run constraints during those months resulted in a reduction in coal operations, with the units remaining offline for almost the entire period. In other words, when allowed to cycle economically (instead of being forced to operate), the model chooses not to operate them. According to our modeling analysis, removing these artificial constraints results in a cost reduction of $130 million of the NPV of revenue requirement.

The third portfolio removed the must run constraints throughout the year and allowed for accelerated retirement. This scenario results in significantly lower coal unit capacity factors. Although not used to generate energy, the units are not immediately retired and remain in the system for a limited number of years mainly as a capacity resource (i.e. it could potentially be used just in case of emergencies and remain available to meet TEP's reserve margin). This additional flexibility resulted in incremental savings of $120 million.

The generation as well as the load and resources balance of the three portfolios are visualized in graphs included in the slide deck presented during TEP's last public workshop on May 20th, attached here as Appendix A. Our recommended portfolio includes the full relaxation of the must run constraints, i.e. economic cycling of the units throughout the year. The recommended portfolio is presented with more detail in a later section.

Energy Efficiency

In IRP proceedings around the country, even in cases of utilities that use capacity expansion modeling to inform their plans, EE is usually treated only as a fixed input to the IRP model. This means that the potential for EE to reduce energy and capacity needs is not compared in a comprehensive "apples-to-apples" way with supply resources, resulting in sub-optimal portfolios with higher cost and emissions. EE is typically estimated through separate studies that result in load reduction in a static way. TEP followed a similar methodology, assuming a certain portfolio of EE measures that were incorporated in the IRP modeling by simply reducing its load forecast.

SWEEP was interested in understanding the full potential of EE in contributing to TEP's capacity and energy needs and its relative cost competitiveness with the continued operation of existing resources and/or the investment in new resources. Furthermore, we were interested in selecting the EE measures that could achieve the maximum savings by examining not only their relative cost and energy output, but also how their hourly profile could reduce system needs during peak hours or hours of lower renewable resource availability. This would also help inform whether TEP's EE portfolio should evolve as more solar is brought online in the region, thus exacerbating overgeneration and ramping issues (i.e. the "duck curve"). This comprehensive examination of EE measures could not be conducted unless EE was also treated as a resource within the capacity expansion model.

To this end, instead of assuming a certain level of EE within the utility's load forecast, we modeled EE measures as resources in EnCompass. The model treated EE like any other resource and was allowed to invest in the EE measures based on their relative value and cost. TEP had collected a comprehensive dataset of EE data and provided detailed information on 19 different groups of EE measures specifying their first-year costs, annual cost escalation, hourly profiles, lifetime, as well as maximum savings available per year. The information provided by TEP is summarized in Table 1 and Figure 1. Table 1 includes information on the maximum annual savings, the lifetime, and first year costs, as well as some information derived from the provided hourly profiles. Figure 1 shows the broad variety of hourly profiles for the different measures. The 19 measures modeled are representative of the broader set of measures in TEP's EE portfolio and include both residential and commercial sectors, and end uses such as lighting, heating, ventilation and air conditioning (HVAC), hot water heating, industrial motors, refrigeration, and so on.

Table 1: Measures Offered in TEP's Energy Efficiency Portfolio

Measure	Maximum Annual Savings (MWh/Year)	Capacity (MW)	Lifetime (Years)	First year costs in 2020 ($/MWh)	Capacity Factor (%)	Coincident Peak* (%)
Com_Daylighting	25374	5.38	17	114.19	54%	61%
Com_HP	8	0.00	19	114.19	29%	63%
Com_HVAC	5239	3.91	20	114.19	15%	60%
Com_HVAC_ProgTstat	14	0.02	11	114.19	10%	0%
Com_Lighting_Exterior	9017	2.59	14	114.19	40%	14%
Com_Lighting_TrEx	13	0.00	3	114.19	100%	100%
Com_Motors	2777	0.58	15	114.19	54%	63%
Com_Refrigeration	723	0.11	12	114.19	78%	94%
Com_Software	1303	0.28	14	114.19	54%	21%
Res_ClothesWasher	232	0.05	11	415.79	48%	59%
Res_HVAC	8851	11.78	19	452.91	9%	72%
Res_HVAC_Clg_Htg	424	0.41	30	452.91	12%	72%
Res_HVAC_Elec	848	0.74	30	452.91	13%	72%
Res_Lighting	42081	19.94	17	45.03	24%	8%
Res_PoolPump	802	0.24	12	215.80	38%	58%
Res_Refrigerator	232	0.03	15	415.79	81%	98%
Res_ShadeTree	593	0.43	37	305.29	16%	39%
Res_Water	191	0.06	10	452.91	39%	27%
Res_LIW	1500	0.56	18	939.86	30%	56%

Table 1 outlines the inputs provided by TEP under a non-disclosure agreement, which is now publicly available on TEP's Resource Planning website through a presentation conducted by SWEEP and Strategen in Appendix A.

Figure 1: TEP's Hourly profiles of Energy Efficiency Measures in MW's

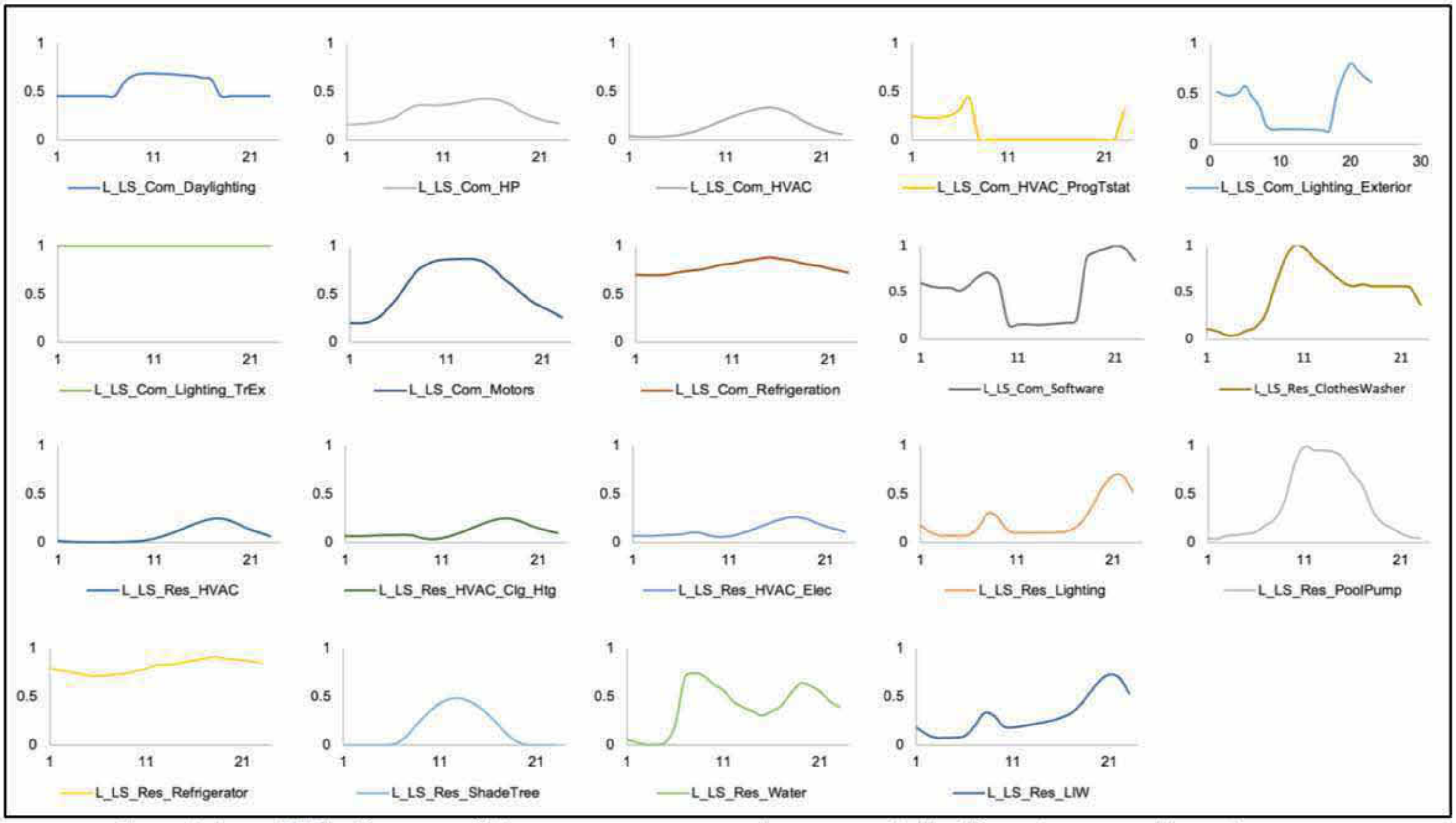


Figure 1 shows TEP's 19 energy efficiency measures averaged over a year to identify each measures' impact on demand based on its time valuation.

The first-year costs as well as the assumed cost escalation of the EE measures, as provided by TEP, are reasonable. Specifically, the first-year costs in 2020 are on the lower end of the EE cost range, while the annual cost escalation is on the higher end. The combination of these two sets of parameters results in future EE costs that are in line with EE cost estimates presented by other utilities.

However, SWEEP firmly believed that TEP has underestimated the maximum potential savings per year that could be achieved. In the first ten years of its energy efficiency program implementation, TEP has succeeded in achieving cumulative savings close to 22%, at costs that were lower than originally predicted. Over the course of the next ten years, TEP's initial EE projection as included in its load forecast would only increase those savings by a few percentage points, up to approximately 27% from the current 22% level. SWEEP believed that given TEP's past performance, and the technological and cost advancements in EE, this level of increase is overly conservative and significantly limits EE's potential in reducing cost and emissions for Arizonans.

Accordingly, SWEEP, together with 32 other organizations submitted a proposal to the Commission outlining the "Joint Stakeholder Proposal for New Energy Rules" including an enforceable standard for 35% cumulative energy efficiency savings by 2030.[8] The Joint Stakeholder Rules also contain updates to the existing Electric Energy Efficiency Standard (EEES) to reduce regulatory barriers to EE program deployment and comprehensiveness.

To evaluate SWEEP's concerns in EnCompass, we gradually increased the maximum potential of the EE measures from TEP's originally selected inputs. Our analysis revealed that the majority of EE measures were cost competitive at increased levels and the model included them in the optimal portfolio up to their maximum savings potential. We modeled three portfolios. The first portfolio included EE based on the TEP provided maximum potential. In the second portfolio, we increased the maximum potential by 50%. The first-year costs, annual cost escalation, and hourly profiles were modeled based on the TEP provided data. The third portfolio assumed an additional 25% increase of the potential of EE measures.

We acknowledge that at higher levels of EE deployment that there may be increased costs for EE measure implementation. However, this is also offset by overall improvements in EE technologies. As with any energy resource, it can be difficult to make future predictions of multiple competing factors. As such, we did not include any changes to the cost of increased measure implementation. However, we believe that higher levels of EE Strategen considered would still be favorable even at slightly higher costs to implement. This could be explored in future sensitivity analyses.

In all portfolios, the model invested in the majority of EE measures up to their maximum potential. In all cases, there were a few measures that were not selected, as they were relatively expensive for the energy savings they could provide. Even though the three portfolios included different levels of investment in each measure due to the increasing maximum potential, the selection of measures remained similar across the three modeling runs. The selected measures are presented in Table 2 below.

Table 2: Energy Efficiency Measures Selected in Capacity Expansion Model

Measure	Maximum Annual Savings (MWh/Year)	Capacity (MW)	Lifetime (Years)	First year costs in 2020 ($/MWh)	Capacity Factor (%)	Coincident Peak* (%)
Predominantly Selected in Capacity Expansion Modeling						
Com_Daylighting	25374	5.38	17	114.19	54%	61%
Com_HP	8	0.00	19	114.19	29%	63%
Com_HVAC	5239	3.91	20	114.19	15%	60%
Com_HVAC_ProgTstat	14	0.02	11	114.19	10%	0%
Com_Lighting_Exterior	9017	2.59	14	114.19	40%	14%
Com_Motors	2777	0.58	15	114.19	54%	63%
Com_Refrigeration	723	0.11	12	114.19	78%	94%
Com_Software	1303	0.28	14	114.19	54%	21%
Res_HVAC	8851	11.78	19	452.91	9%	72%
Res_HVAC_Clg_Htg	424	0.41	30	452.91	12%	72%
Res_HVAC_Elec	848	0.74	30	452.91	13%	72%

[8] Joint Stakeholder Proposal for New Energy Rules, https://docket.images.azcc.gov/E000005275.pdf

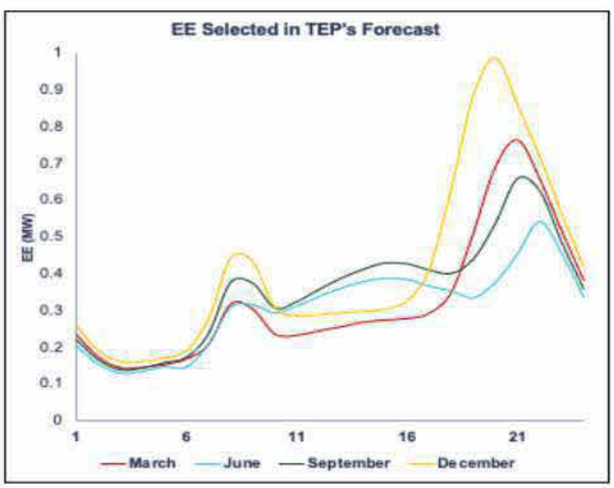
Res_Lighting	42081	19.94	17	45.03	24%	8%
Res_ShadeTree	593	0.43	37	305.29	16%	39%
Not Selected						
L_LS_Com_Lighting_TrEx	13	0.00	3	114.19	100%	100%
L_LS_Res_ClothesWasher	232	0.05	11	415.79	48%	59%
L_LS_Res_PoolPump	802	0.24	12	215.80	38%	58%
L_LS_Res_Refrigerator	232	0.03	15	415.79	81%	98%
L_LS_Res_Water	191	0.06	10	452.91	39%	27%
L_LS_Res_LIW	1500	0.56	18	939.86	30%	56%

Table 2 outlines the inputs utilized in the Capacity Expansion Model.

Increasing the available energy savings, led to an increased investment in EE in the three portfolios which enabled not only cost savings due to avoided energy, but also enabled lower capacity investments (or earlier retirement of coal units).

It is worth noting that the optimal portfolio of EE measures as selected in EnCompass is characterized by a different hourly profile, especially during summer months and during hours when TEP load is usually at its peak. EnCompass is an ideal tool for capacity expansion modeling due to its ability to select a diversity of EE measures and select more EE measures with high peak coincidence than were in TEP's base assumptions. Even though peak coincidence enhances value, there are still cost-effective EE measures with lower peak coincidence that are selected based on energy value. Thus, in addition to the energy savings, EE can deliver significant capacity benefits by reducing load during peak hours. This reduction in capacity needs is captured within a capacity expansion model but is not captured in a production cost model. Consequently, when TEP manually selects generation resource portfolios and evaluates the benefits of increased EE by simulating the exact same generation portfolio with the only difference of EE levels, it underestimates the benefits that EE can deliver to the system.

Figure 2: Comparison of EE in TEP's Forecast and Strategen's Forecast



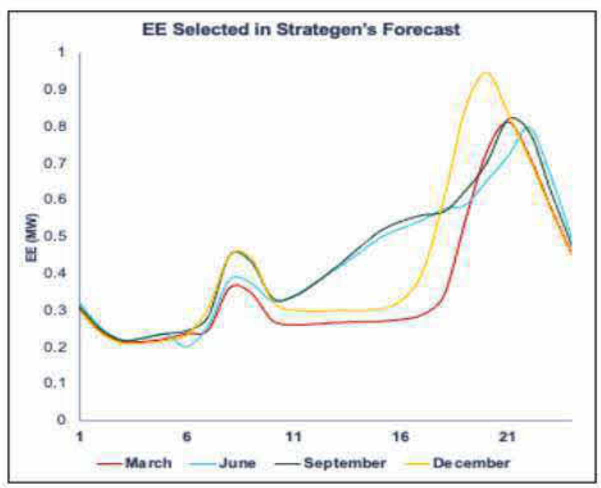


Figure 2 illustrates how energy efficiency delivers benefits during peak hours and during different months in the year.

Based on the EnCompass analysis, the Strategen recommended portfolio includes 40% energy savings by 2030 and leads to $234 million of cost savings compared to TEP's base assumptions by reducing the system's energy and capacity needs.

Recommended Portfolio

Our recommended portfolio includes economic cycling of the coal units, as well as accelerated retirement, and 40% energy savings by 2030. The generation and load and resources graphs are included below. Key elements of the portfolio include:

- Economic cycling of all coal units starting in 2020
- Unit 1 at the Springerville Generating Station retires by the end of 2024
- Unit 2 at the Springerville Generating Station retires by the end of 2031
- 40% cumulative savings from energy efficiency by 2030.

Figure 3: Recommended Portfolio Generation Mix

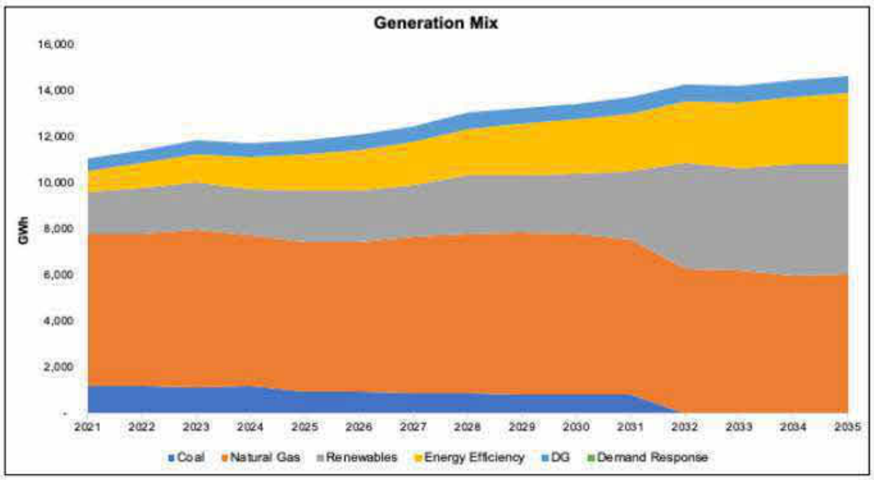
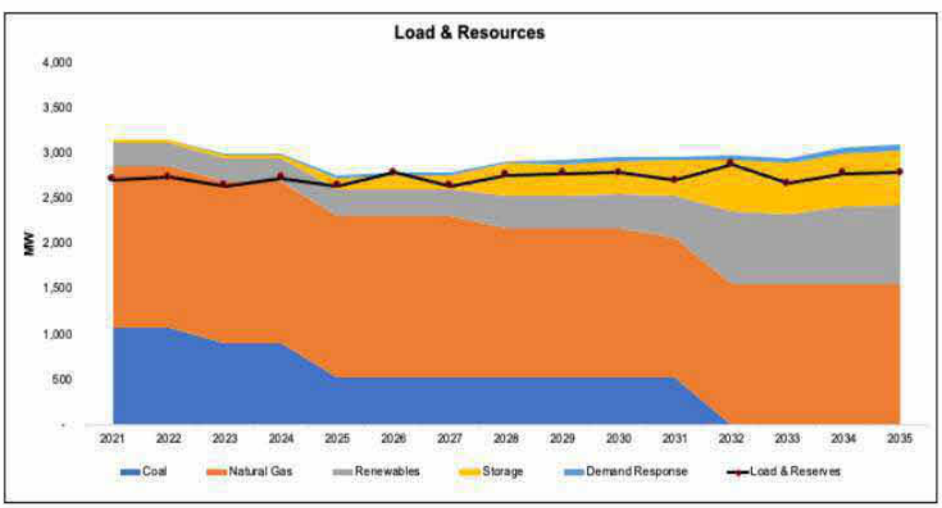


Figure 4: Recommended Loads and Resources



Comparing Recommendations with TEP's Preferred Portfolio

Table 3: Key Assumptions in TEP's and Strategen/SWEEP's Preferred Portfolios Through 2035

Load/Resource Assumptions	TEP Preferred Portfolio (Production Cost Model)	Strategen/ SWEEP Preferred Portfolio (Capacity Expansion Model)
Load Forecast	• Annual growth rate of ~0.8%.[9]	• Same as TEP's Preferred Portfolio.
Renewable Energy	• 2,000 MW planned additional wind and solar. • 65.6% Solar by 2035. • 34.4% Wind by 2025.	• 1815 MW of additional solar and wind. • 50% Renewables by 2030.
Distributed Generation (Non-Utility)	• 350 MW by 2035.	• Same as TEP's Preferred Portfolio.
Energy Storage	• 1,400 MW planned addition of storage.	• 700 MW by 2035.
Energy Efficiency	• Increasing from 1.3% to 1.5% retail sales energy savings annually.	• 40% cumulative savings by 2030. • 1.6% over the 15-year period with 1.9% and the first few years targeting more measures.
Demand Response (DR)	• 4% annual growth in DR Capacity after 2021 resulting in 66MW in 2035.	• 65 MW by 2035.
Coal Operation Determinants	• Springerville seasonal operations begin in 2023.	• Exclusively economic cycling of coal units starting 2020.
Existing Fossil Fuels	• San Juan 1 retires in 2022. • Springerville Unit 1 retires 2027. • Four Corners retires 2031. • Springerville Unit 2 Retires 2032 • Sundt Unit 3 Retires 2032. • 1073 MW Planned Coal retirement leaves complete exit by 2032.	• San Juan 1 retires in 2022. • Springerville 1 retires in 2024. • Springerville 2 in 2031. • Four Corners retires 2031. • Sundt Unit 3 Retires 2030.
Natural Gas (Combined Cycle or Reciprocating Internal Combustion Engines (RICE))	• Does not include the addition of any new fossil-fuel resources.	• Does not include the addition of any new fossil-fuel resources.

Conclusion

In developing its IRP, TEP has outlined four primary objectives: (a) Affordability, (b) Reliability of Service, (c) Risk mitigation, and (d) GHG emission reductions. Those objectives are many times presented as competing leading to unavoidable tradeoffs between cheaper, cleaner, or more reliable energy. Although this might have been the case in the early years of renewable energy, the cost of solar and wind technologies has dramatically fallen leading renewable resources to not only be the most environmentally friendly option, but also the most affordable one. Furthermore, storage resources can provide the necessary system reliability. Distributed resources provide flexibility in contrast to the centralized thermal resources of the past years that locked in huge amounts of capital in long-lived assets which eventually became uneconomic before their scheduled time.

To be able to fully capture the emissions and cost savings of renewable energy and EE, TEP should revise practices that may have made sense in the past, but do not anymore. Coal units are not baseload units anymore; on the contrary, they have become some of the most expensive resources in the system.

TEP is making steps towards the right direction by not considering any investment in new fossil fuel resources. However, there are still huge amounts of savings available by unlocking the following actions:

1. Revising its must-run practices for coal units and consider economic cycling instead.
2. Investing in additional EE above and beyond the levels proposed by TEP in its IRP by implementing a broad portfolio of EE measures.

Both recommended changes result in saving money on customers' monthly bills, reducing greenhouse gas emissions, planning ahead for communities dependent on power plant employment, and providing significant flexibility in the system without adding or removing significant amounts of resources in the early years. These actions provide a balance between early action in reducing emissions and allowing TEP to take advantage of reductions in storage and renewable technologies costs, by shifting the need for new investment in later years (or in the case of EE reducing the need for new investment altogether).

Similarly, EE can reduce TEP's energy and capacity needs, significantly mitigating TEP's exposure to fuel price risk, technology cost fluctuations, and other uncertain factors.

Appendix A: TEP's IRP Public Workshop, May 20th, 2020

[9] Page 34, https://www.tep.com/wp-content/uploads/TEP-2020-Integrated-Resource-Plan-Lo-Res.pdf

TEP IRP Analysis

TEP IRP Workshop, May 2020
Prepared by Strategen Consulting for Southwest Energy Efficiency Project (SWEEP)

Southwest Energy Efficiency Project (SWEEP)

- Non-profit public interest organization, founded 2001
- Advances policies and programs to stimulate greater energy efficiency in six western U.S. states
- Advances energy efficiency in the buildings, transportation, industrial and utility sectors

SWEEP

www.swenergy.org

STRATEGEN

Strategen is a mission-driven professional services firm dedicated to decarbonizing the grid

ASSOCIATIONS

Strategen co-founded and manages the California Energy Storage Alliance (CESA) and the Global Energy Storage Alliance (GESA). Through these organizations, Strategen's policy work has been pivotal in building the energy storage industry in California, the US, and around the world.

CONSULTING

Since 2005, Strategen Consulting provides analysis and insight to public sector leaders, utilities, developers, and global corporations helping them to achieve transformational and sustainable clean energy strategies.

EVENTS

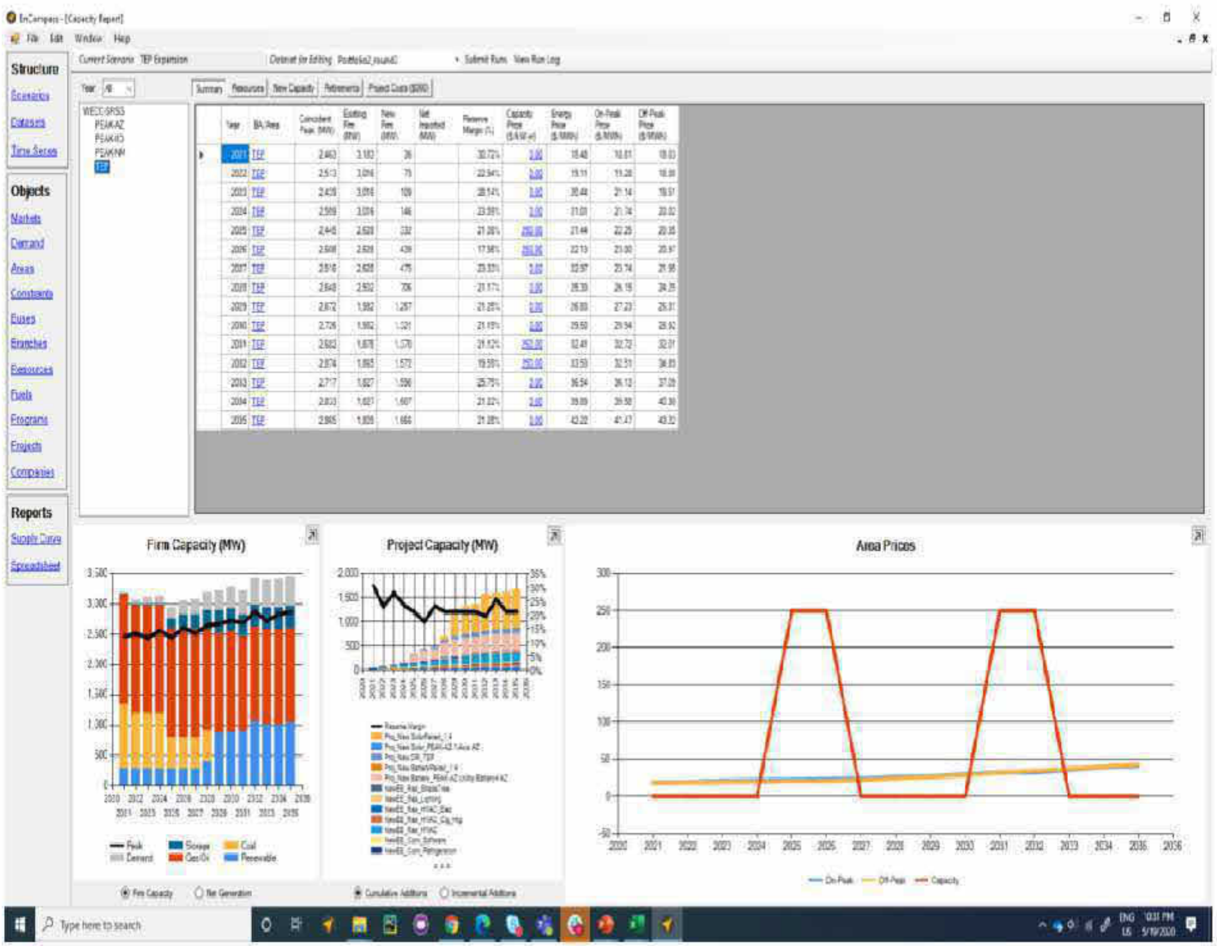
Strategen excels in stakeholder engagement, via customized small and large events.
Strategen founded Energy Storage North America (ESNA), the largest grid-connected storage conference in North America. ESNA connects over 2000 participants from 30+ countries.

Overview

- Project Objective
- Modeling Methodology
- Portfolios
- Modeling Results
- Comparison to TEP portfolios
- Conclusions

Modeling Methodology

- TEP IRP modeling: Production Cost Modeling using *Aurora*
- SWEEP/Strategen modeling: Capacity Expansion Modeling using *EnCompass*



Capacity Expansion Modeling (CEM)

What is the least cost portfolio of resources that should be built to reliably meet electricity demand in the next decades?

Inputs

- List of future technologies (cost & simplified performance characteristics)
- Fuel prices & renewable resource potential
- Environmental policies

Model

Objective:
Minimize Investment and Operational Cost

- Constraints:
- Supply = Demand
- Simplified grid & generation constraints
- Policy Constraints

Outputs

- Optimal resource portfolio
- Cost of Electricity over the next decades
- Policy assessment indicators
- Minimum capital and O&M system cost of meeting demand in the next decades

Production Cost Modeling (PCM)

What is the least cost dispatch of a given system of generators to reliably meet load in every hour of the day at every location?

Inputs

- List of generating units (detailed cost & performance characteristics)
- Detailed Grid Representation
- Fuel prices & Renewable Resource Potential

Model

Objective:
Minimize Operational Cost

Constraints:
Supply = Demand
Detailed grid & generation constraints

Outputs

- (Sub) hourly unit generation schedules & curtailment
- Locational Marginal Electricity & Ancillary Services Prices
- Minimum O&M system cost of meeting demand every hour

Questions driving SWEEP/Strategen modeling

Optimal Resource Mix

- *What is the least cost mix of resources for TEP's system?*

Coal Resources

- *When should coal units be retired based on economic considerations (if given the option)?*
- *What are the environmental impacts from early retirement?*
- *How should coal units be dispatched if operated economically? (i.e. absent "must-run" constraints)*

Energy Efficiency & Demand Side Management

- *How much Energy Efficiency is economic when modeled as a resource option (vs. fixed load-modifying assumption)?*
- *How does the selection of EE measures impact TEP's energy and capacity needs?*
- *How selection of EE measures vary based on cost, hourly shape, coincident peak, and savings?*

Coal Operations

- Historically, coal units have been designated as “must run”.
- Must-run units remain online and generate electricity regardless of system economics.
- Although there were reasons behind this practice, the market’s changing economics call for a different approach: economic cycling.
- SWEEP/Strategen examined the relaxation of those constraints as a transition to a cleaner system for TEP.

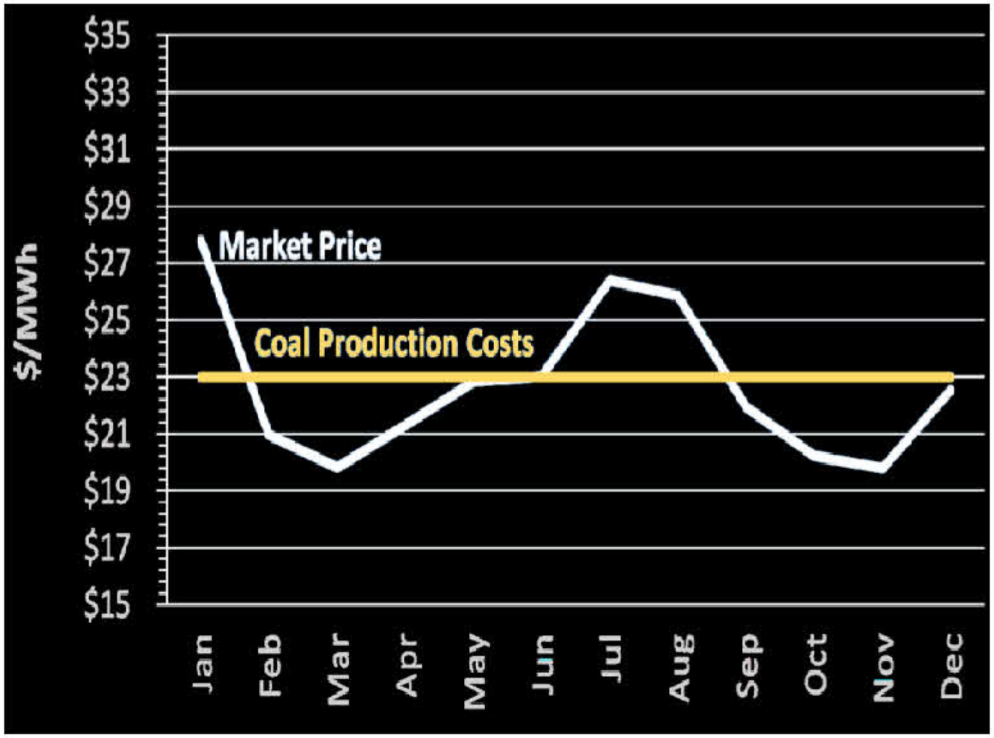


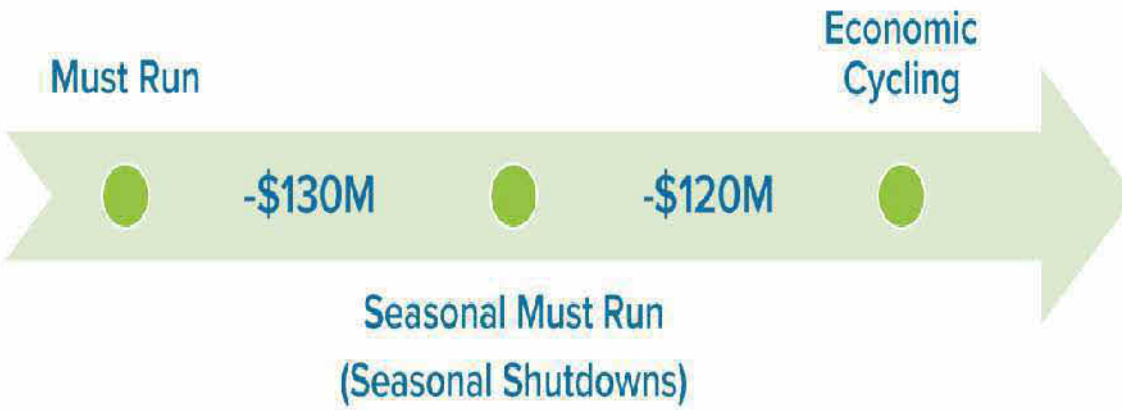
Image source: UCS

Portfolio Assumptions – Coal Portfolios

	Coal Units		Energy Efficiency
Portfolio 1	Fixed Retirement Four Corners – 2031 Springerville – after 2035	Must Run	Model can select EE measures based on their cost competitiveness
Portfolio 2	Economic Retirement (Earliest Retirement 12/31/2023)	Summer Must Run	Model can select EE measures based on their cost competitiveness
Portfolio 3b	Economic Retirement (Earliest Retirement 12/31/2023)	Economic Cycling	Base EE (similar to TEP base assumption)

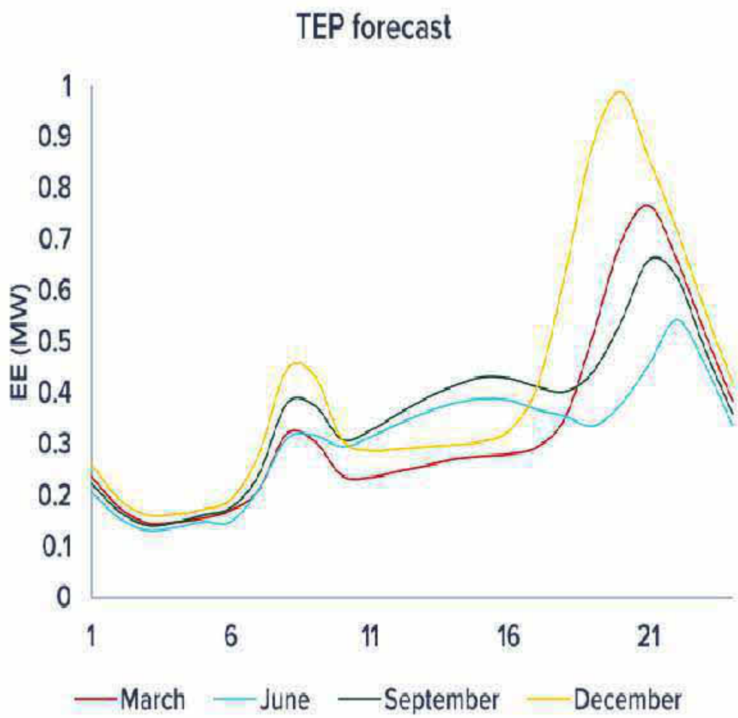
Results – Coal Operations

- Coal units are uneconomic with marginal costs higher than the rest of TEP's portfolio - even more so when fixed O&M costs and capital expenses are accounted for.
- Incremental savings can be achieved with the relaxation of must run constraints on coal units. Moving from portfolio 1 (must run) to portfolio 3b (economic cycling) can reduce the revenue requirement approximately $250M).



- Economic Operations are similarly important to economic retirement and can lead to *cost and emissions* savings (emissions equivalent of shutting down a few years early) while allowing for a just transition
  - Examining economic operations is especially important due to upcoming coal contract negotiations

Energy Efficiency in TEP Base Assumptions



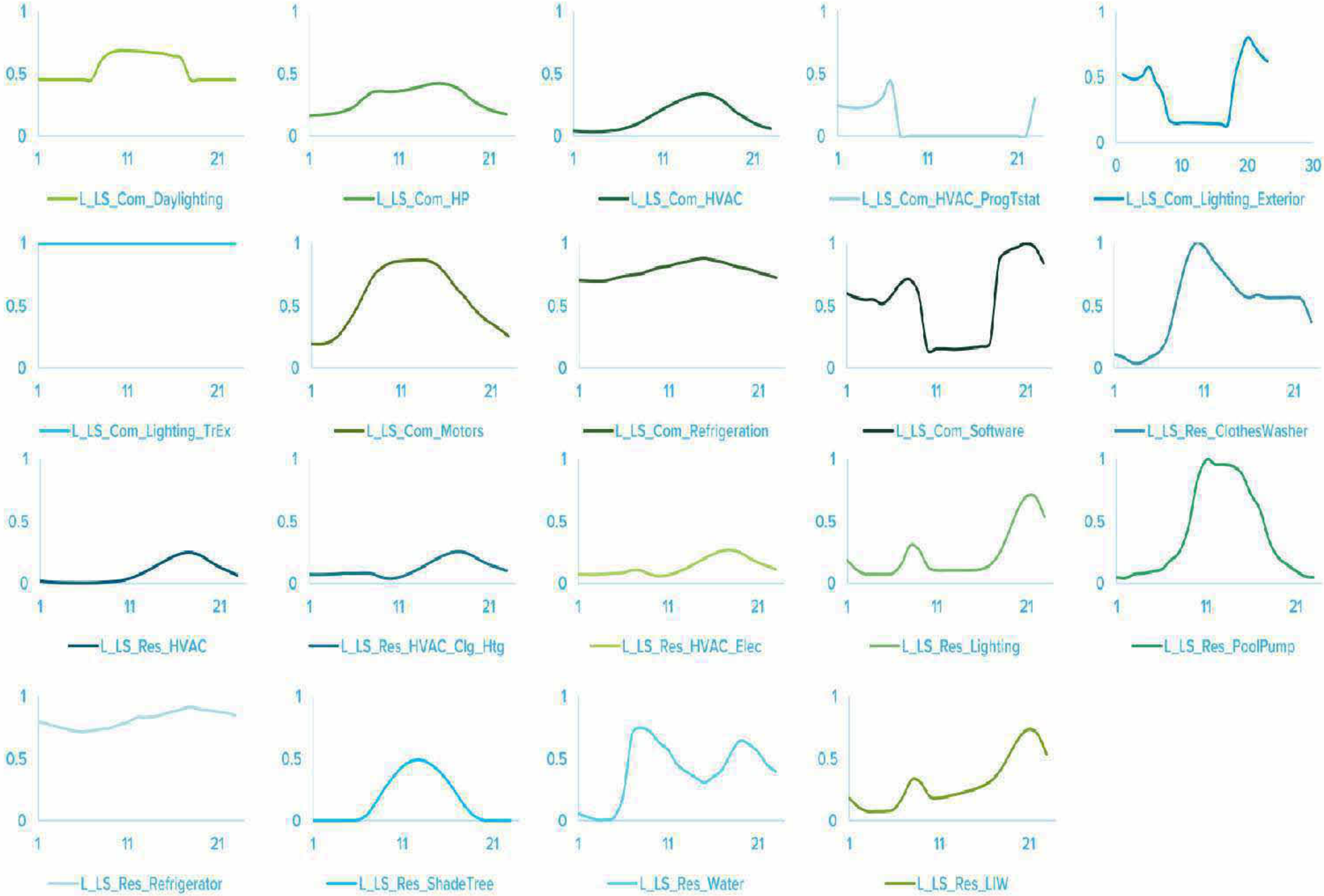
TEP Base EE portfolio consists predominantly of Residential Lighting measures.

Energy Efficiency

- TEP provided costs and hourly profiles of 19 EE measures:

Measure	Maximum Annual Savings (MWh/Year)	Capacity (MW)	Lifetime (Years)	First year costs in 2020 ($/MWh)	Capacity Factor (%)	Coincident Peak* (%)
L_LS_Com_Daylighting	25374	5.38	17	114.19	54%	61%
L_LS_Com_HP	8	0.00	19	114.19	29%	63%
L_LS_Com_HVAC	5239	3.91	20	114.19	15%	60%
L_LS_Com_HVAC_ProgTstat	14	0.02	11	114.19	10%	0%
L_LS_Com_Lighting_Exterior	9017	2.59	14	114.19	40%	14%
L_LS_Com_Lighting_TrEx	13	0.00	3	114.19	100%	100%
L_LS_Com_Motors	2777	0.58	15	114.19	54%	63%
L_LS_Com_Refrigeration	723	0.11	12	114.19	78%	94%
L_LS_Com_Software	1303	0.28	14	114.19	54%	21%
L_LS_Res_ClothesWasher	232	0.05	11	415.79	48%	59%
L_LS_Res_HVAC	8851	11.78	19	452.91	9%	72%
L_LS_Res_HVAC_Clg_Htg	424	0.41	30	452.91	12%	72%
L_LS_Res_HVAC_Elec	848	0.74	30	452.91	13%	72%
L_LS_Res_Lighting	42081	19.94	17	45.03	24%	8%
L_LS_Res_PoolPump	802	0.24	12	215.80	38%	58%
L_LS_Res_Refrigerator	232	0.03	15	415.79	81%	98%
L_LS_Res_ShadeTree	593	0.43	37	305.29	16%	39%
L_LS_Res_Water	191	0.06	10	452.91	39%	27%
L_LS_Res_LIW	1500	0.56	18	939.86	30%	56%

*based on load forecast provided by TEP, peak occurs in July at 17:00


L_LS_Com_Daylighting
L_LS_Com_HP
L_LS_Com_HVAC
L_LS_Com_HVAC_ProgTstat
L_LS_Com_Lighting_Exterior
L_LS_Com_Lighting_TrEx
L_LS_Com_Motors
L_LS_Com_Refrigeration
L_LS_Com_Software
L_LS_Res_ClothesWasher
L_LS_Res_HVAC
L_LS_Res_HVAC_Clg_Htg
L_LS_Res_HVAC_Elec
L_LS_Res_Lighting
L_LS_Res_PoolPump
L_LS_Res_Refrigerator
L_LS_Res_ShadeTree
L_LS_Res_Water
L_LS_Res_LIW

Portfolio Assumptions – EE Portfolios

	Coal Units		Energy Efficiency
Portfolio 3a	Economic Retirement (Earliest Retirement 12/31/2023)	Economic Cycling	Base EE (similar to TEP base assumption)
Portfolio 3b	Economic Retirement (Earliest Retirement 12/31/2023)	Economic Cycling	Model can select EE measures based on their cost competitiveness
Portfolio 3c	Economic Retirement (Earliest Retirement 12/31/2023)	Economic Cycling	Model can select EE measures based on their cost competitiveness (increased EE Technical Potential)

Economic EE measures

Measure	Maximum Annual Savings (MWh/Year)	Capacity (MW)	Lifetime (Years)	First year costs in 2020 ($/MWh)	Capacity Factor (%)	Coincident Peak* (%)
Predominantly Selected in Capacity Expansion Modeling						
L_LS_Com_Daylighting	25374	5.38	17	114.19	54%	61%
L_LS_Com_HP	8	0.00	19	114.19	29%	63%
L_LS_Com_HVAC	5239	3.91	20	114.19	15%	60%
L_LS_Com_HVAC_ProgTstat	14	0.02	11	114.19	10%	0%
L_LS_Com_Lighting_Exterior	9017	2.59	14	114.19	40%	14%
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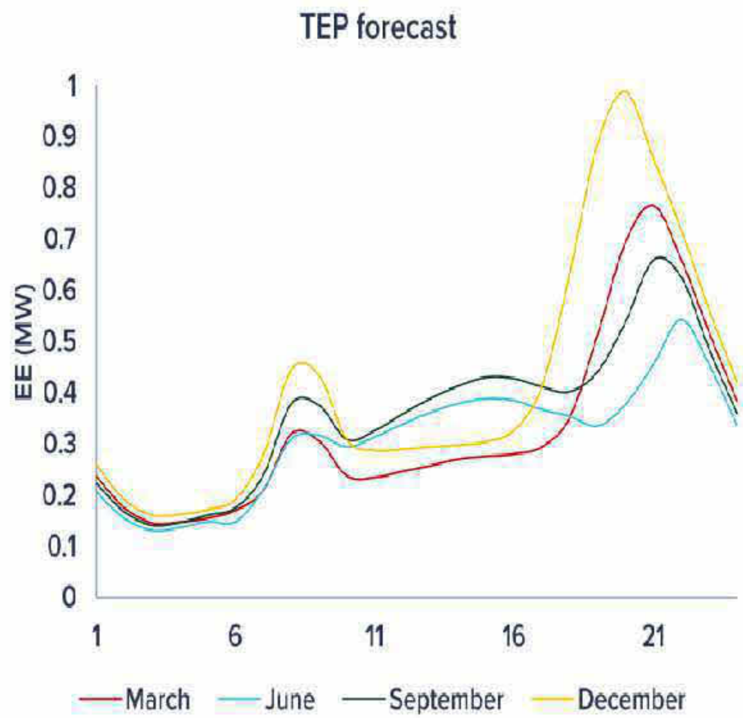
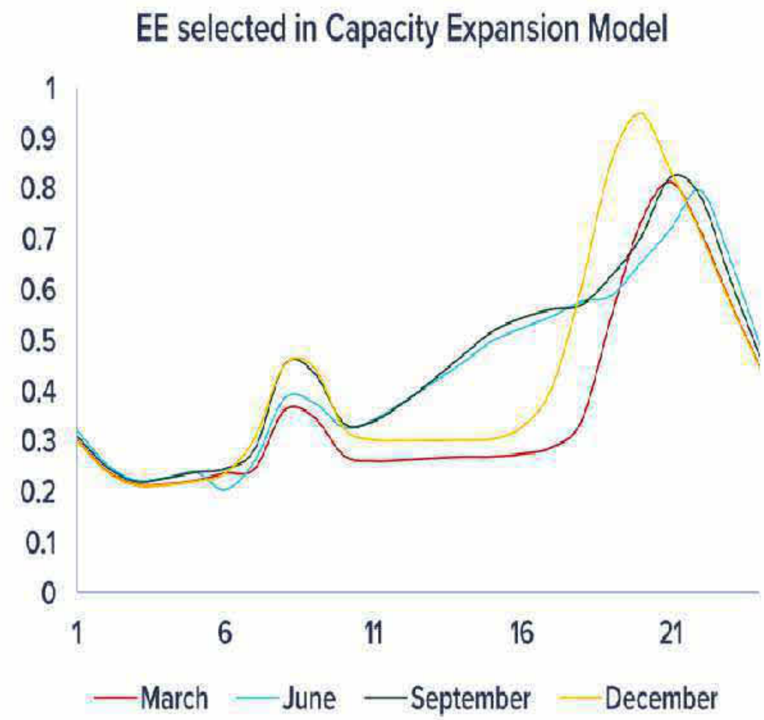
L_LS_Res_HVAC_Clg_Htg	424	0.41	30	452.91	12%	72%
L_LS_Res_HVAC_Elec	848	0.74	30	452.91	13%	72%
L_LS_Res_Lighting	42081	19.94	17	45.03	24%	8%
L_LS_Res_ShadeTree	593	0.43	37	305.29	16%	39%
Not Selected						
L_LS_Com_Lighting_TrEx	13	0.00	3	114.19	100%	100%
L_LS_Res_ClothesWasher	232	0.05	11	415.79	48%	59%
L_LS_Res_PoolPump	802	0.24	12	215.80	38%	58%
L_LS_Res_Refrigerator	232	0.03	15	415.79	81%	98%
L_LS_Res_Water	191	0.06	10	452.91	39%	27%
L_LS_Res_LIW	1500	0.56	18	939.86	30%	56%

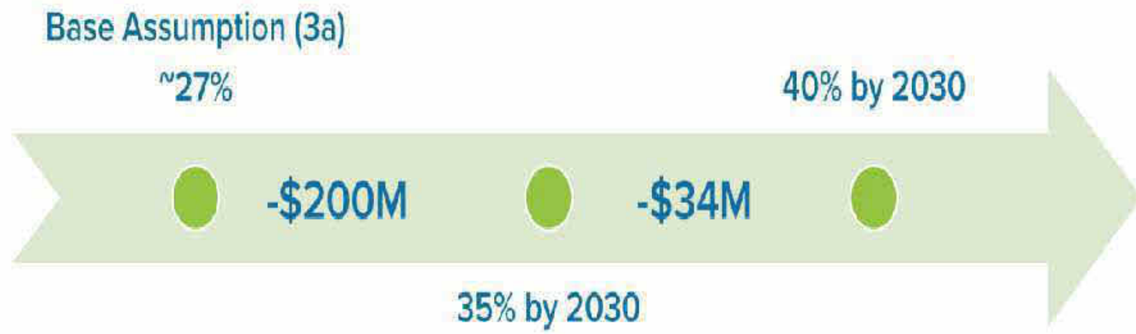
Modeling Energy Efficiency as a Supply Resource





Results – Energy Efficiency

- Modelling energy efficiency as a non-dispatchable resource (based on the hourly profiles and costs provided by TEP) indicates that EE is cost effective at a level much higher than what currently included in the TEP base assumptions

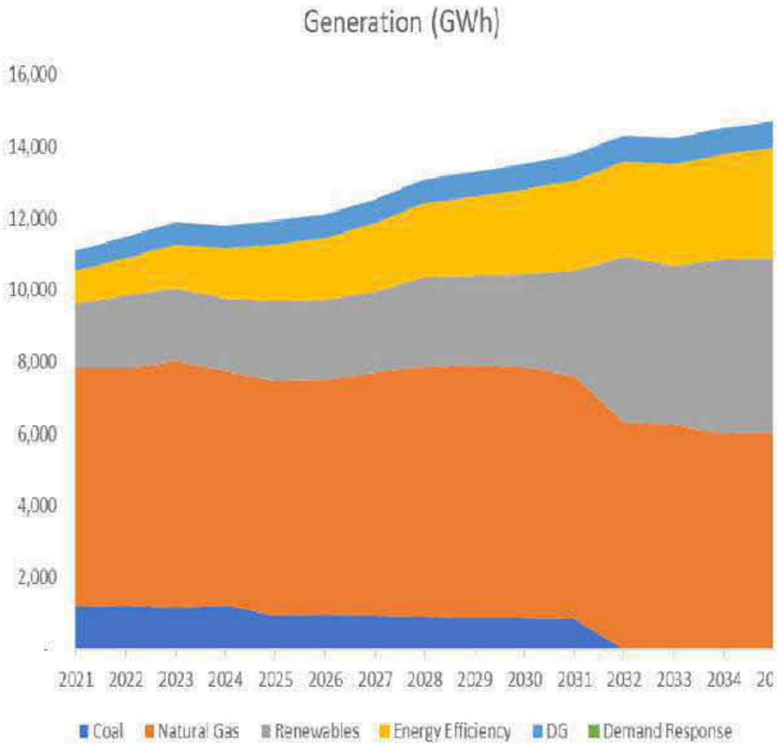


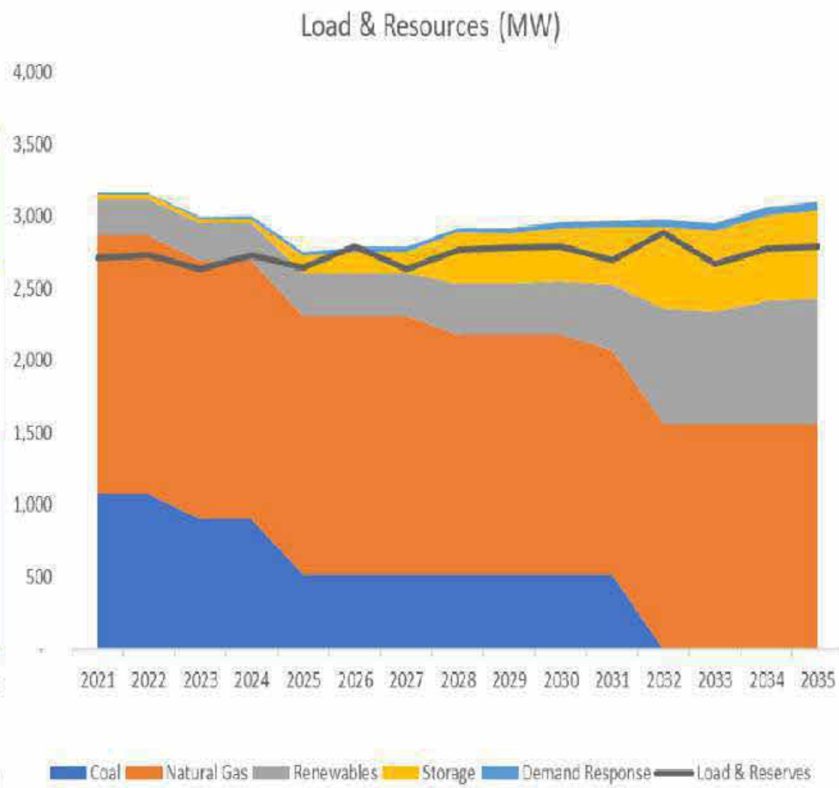
- Currently, the amount of EE in the model was mainly limited by the EE measures available (i.e. assumed technical potential) and not their cost-competitiveness.

Savings are not additive to the coal operations results

Portfolio 3c (includes economic cycling & 40% EE by 2030)

- Includes: 1) economic cycling for coal & 2) 40% EE by 2030
- Results: $234 million reduction in NPV cost by 2030 (versus base portfolio)





Observations on TEP's Modeled Portfolios

Key Takeaways

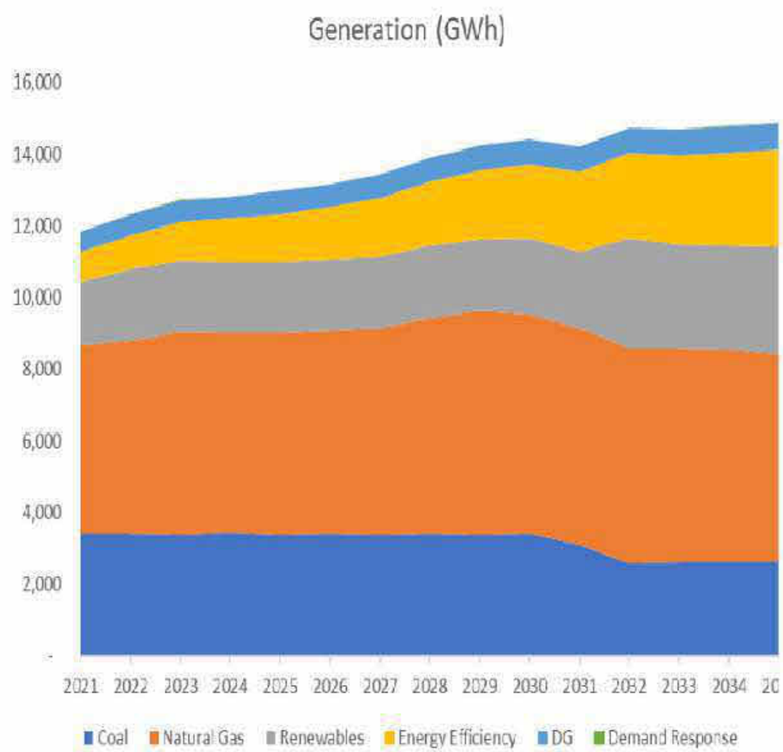
- Allowing economic retirement and/or economic cycling of coal units yields significant portfolio level savings (e.g. ~$250M reduced revenue requirement when both are included)
- EE is selected as a cost-effective resource above TEP base case assumptions when given the option.
- Applying EE load shapes can better tailor the EE portfolio to the most cost-effective measures (i.e. optimizing among factors such as cost, lifetime savings, and peak-coincidence)
- The least cost portfolio in Strategen's analysis included *both* economic cycling and high EE (i.e. 40% by 2030). This yielded NPV RR that was $286M less than the base case (Scenario 1 versus Scenario 3c).

Appendix

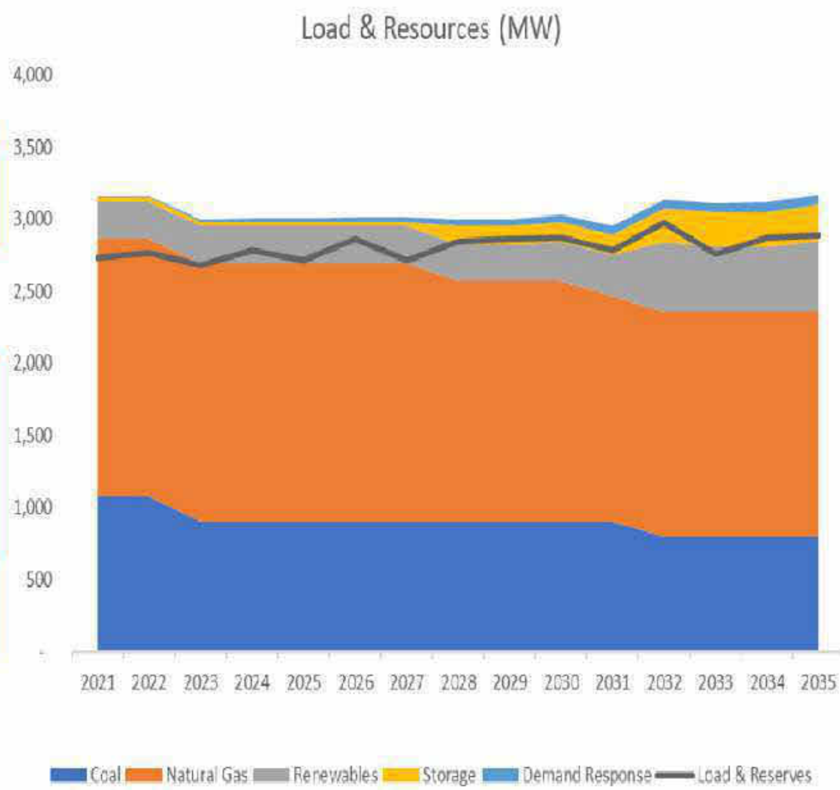
Energy Modeling

	Capacity Expansion Model	Production Cost Model
Planning horizon	Decades	Weeks
Optimization Step / Temporal Resolution	(1-5) Years	(Sub) hourly
Spatial Resolution	Detailed network	Simplified network
Objective (least cost)	Investment & Operations	Operations
Input	• Set of future technologies • Fuel prices & renewable resource potential • Policies	• Existing grid & generation Infrastructure • Fuel prices & renewable resource potential
Output	Optimal Grid & Generation Infrastructure	(Sub) hourly unit generation schedules & prices
Economic Dispatch	Yes	Yes
Set of hours	Use of representative hours	Modeling every hour in chronological order
Operational Constraints	Simplified	Detailed
Endogenous investment & retirement	Yes	No

Portfolio 1

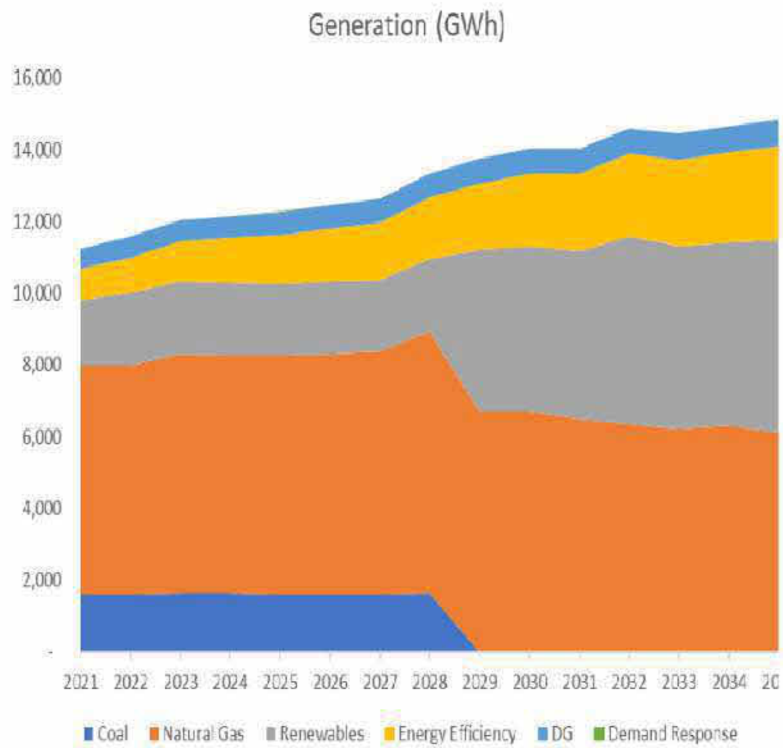


Generation (GWh)
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
-
2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 20
Coal
Natural Gas
Renewables
Energy Efficiency
DG
Demand Response

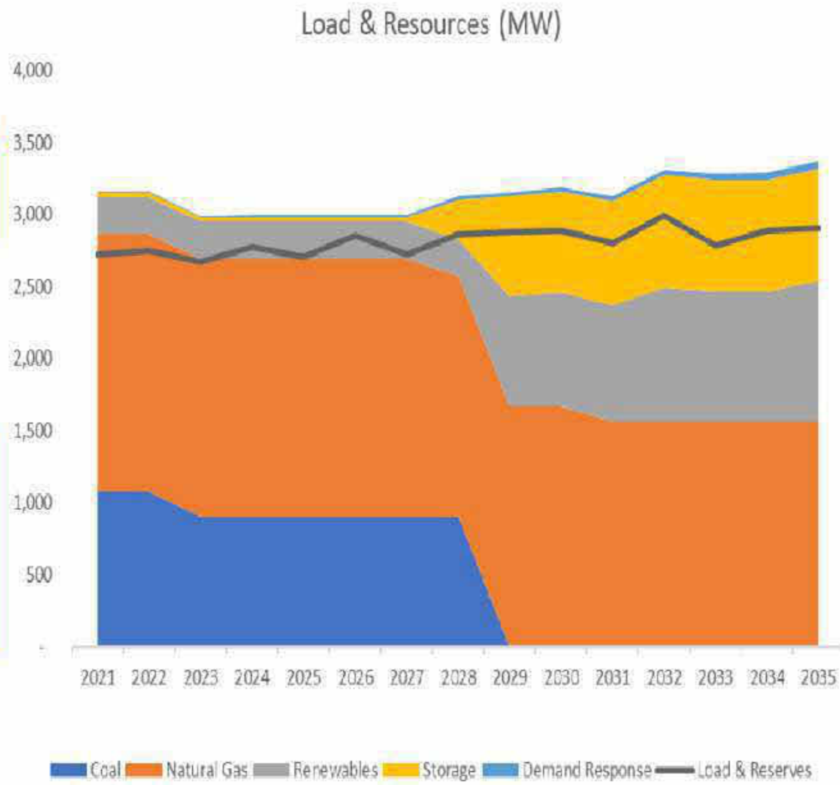


Load & Resources (MW)
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
-
2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035
Coal
Natural Gas
Renewables
Storage
Demand Response
Load & Reserves

Portfolio 2

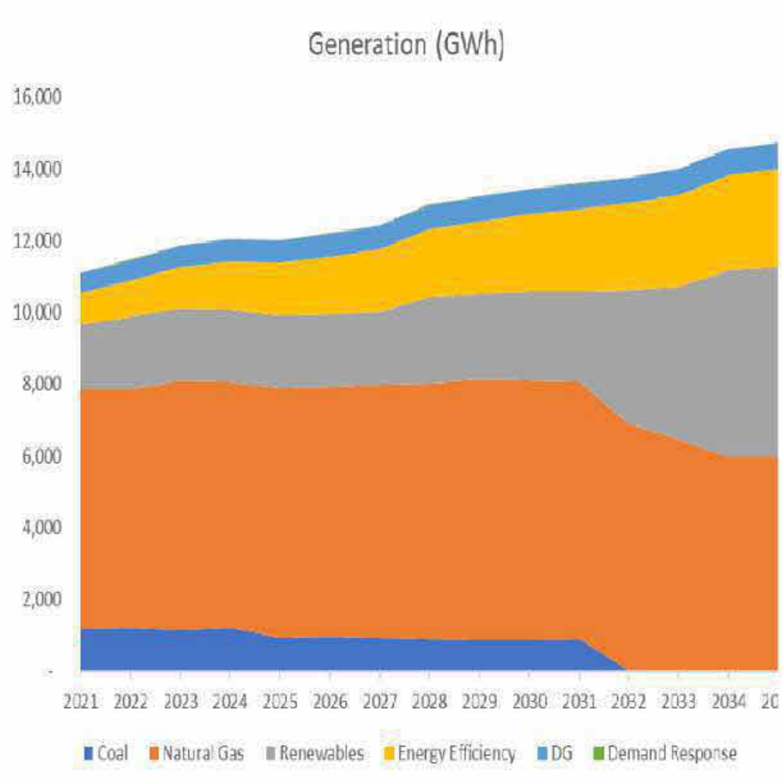


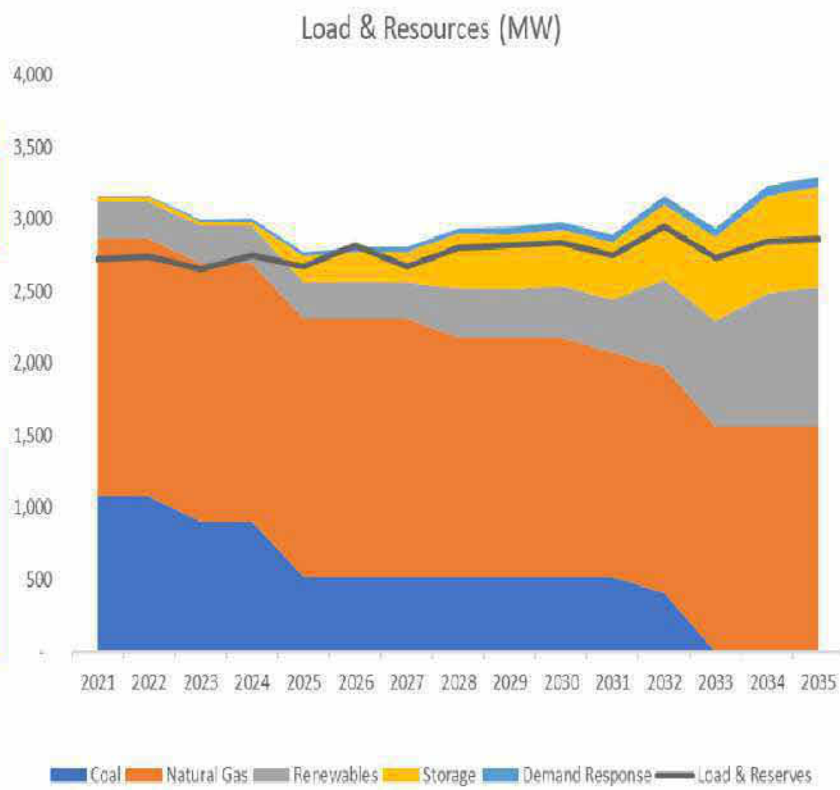
Generation (GWh)
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
-
2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 20
Coal Natural Gas Renewables Energy Efficiency DG Demand Response



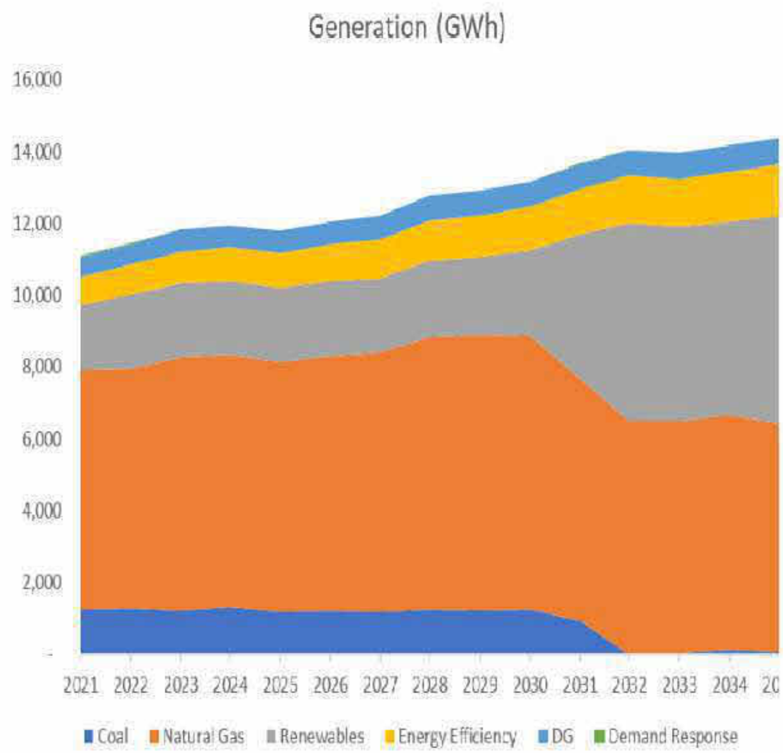
Load & Resources (MW)
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
-
2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035
Coal Natural Gas Renewables Storage Demand Response Load & Reserves

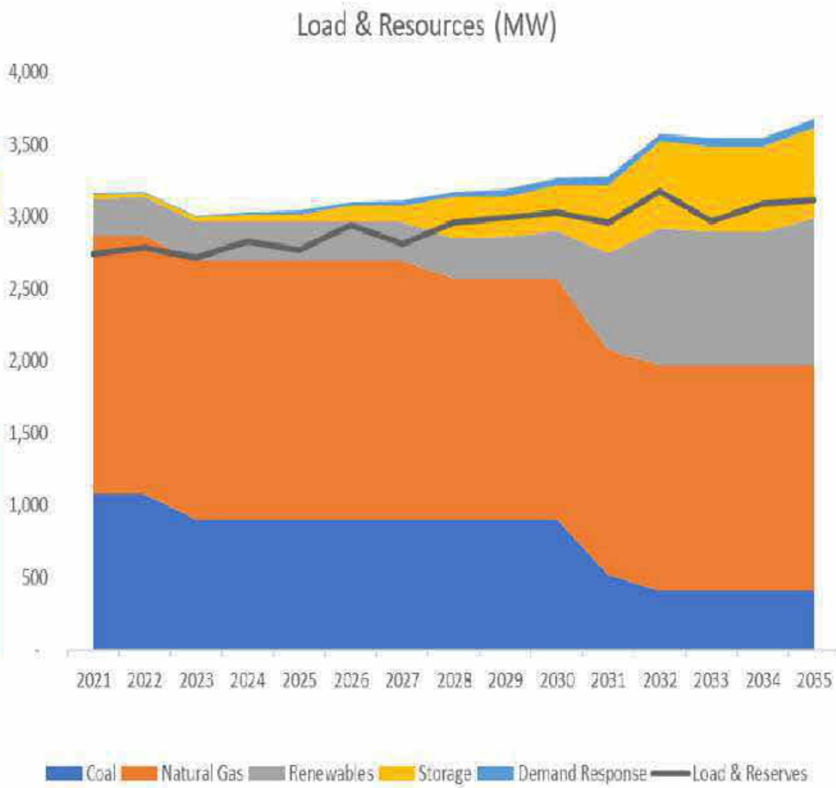
Portfolio 3b



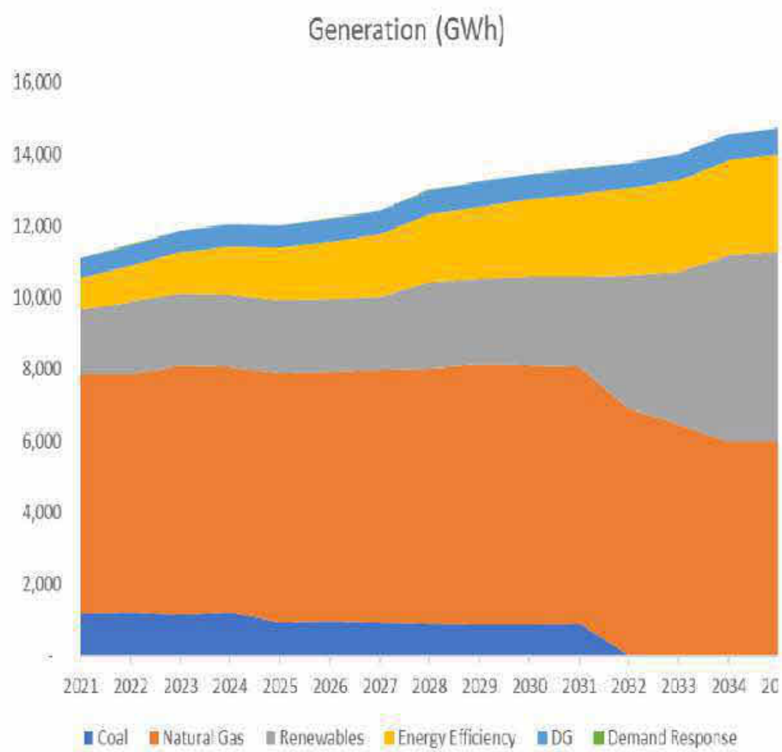


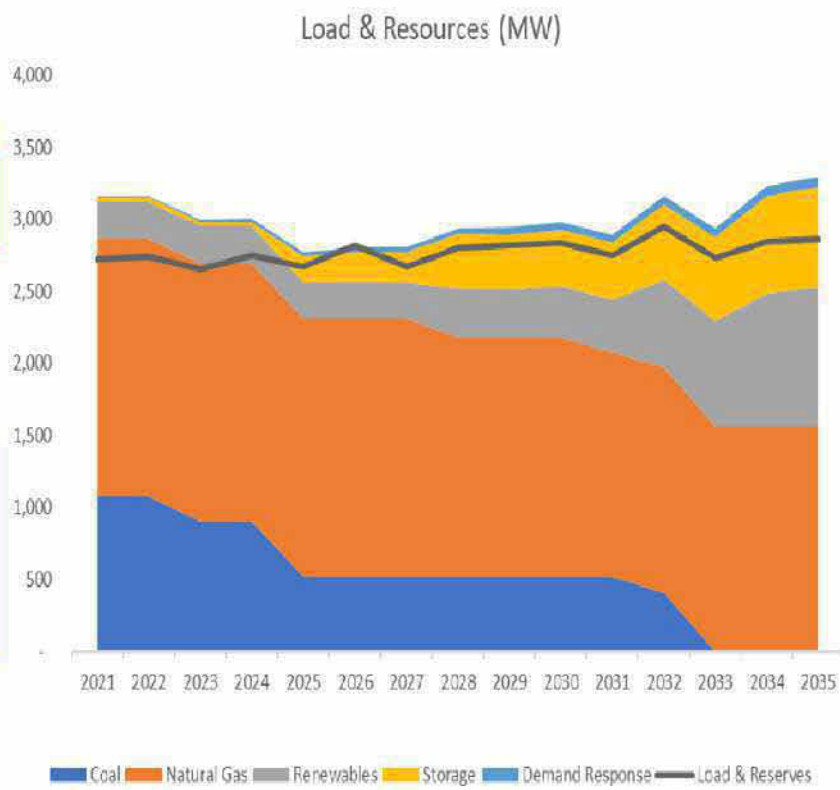
Portfolio 3a





Portfolio 3b





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Observations on TEP's Modeled Portfolios